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Executive Summary

EIA forecasts of the *average* cost of generation in New England, New York, and mid-Atlantic states suggests that if offshore wind is able to meet NREL's cost projections, it will be largely competitive with the average cost of generation in these regions between 2015 and 2020. This is particularly true considering that the regional forecasts represent *one-year* costs, whereas the NREL wind estimates are *levelized* costs. Furthermore, the *marginal* cost of generation – a more relevant comparison than average cost, yet one for which little public data exists – is projected to largely converge with average costs beyond 2010 (as economic theory would predict), implying that the distinction between marginal and average costs may not be all that critical over the time frame of concern.

The competitiveness of wind power should not, however, be evaluated solely with respect to wholesale price forecasts or long-run marginal costs. Other factors must be considered, such as wind integration costs, capacity value, production profiles and locational value, potential revenue from emissions credit markets, wind's hedge value against natural gas price risk, and potential revenue from the sale of renewable energy credits (RECs). In particular, it is worth emphasizing that over long time frames such as the 2015-2020 period in question, forecasts of generation costs will be heavily dependent on fuel price assumptions, and that all of the forecasts presented herein are based on fuel price forecasts developed prior to the most recent surge in natural gas prices. With natural gas prices significantly higher now than they were at the end of last year (when the forecasts were developed), current forecasts of generation costs would likely be higher as well, making offshore wind – which is not affected by fluctuations in natural gas prices – relatively more attractive. Incremental revenue from REC sales and perhaps even emissions credits – neither of which is available to conventional fossil-fueled generation – increase the competitiveness of offshore wind.

Introduction

As we understand it, U.S. DOE is interested in better understanding the economics of offshore wind power, primarily focused on the Northeastern United States. NREL has provided a forecast of the potential for significant reductions in the cost of delivered electricity from offshore wind installations over time. Our task was to evaluate the "market value" of this resulting generation. As shown below, we find that offshore wind, if it were able to meet the cost projections provided by NREL, would likely become a very attractive resource option for the Northeastern U.S. (or wherever it could be developed, for that matter).

We begin this memo by briefly discussing the forecasted cost of wholesale electricity in the Northeastern U.S. We then discuss some of the other "non-commodity-energy" values of renewable energy. Note that, unless noted otherwise, all prices presented here are in constant 2002 dollars. Also note that our focus is primarily on New England, because this is where we have been able to identify the most data, but the basic results of our analysis would not change dramatically when considering other regions, including New York and the Mid-Atlantic; some data on these latter two regions are included.

Wholesale Price Forecasts and Long-Run Marginal Costs

The figure below shows the EIA's forecast of *average* electricity generation costs in New England, New York, and the mid-Atlantic (from AEO 2003), along with an estimate of *marginal* generation costs in New England from a cost impact study of the Massachusetts RPS conducted around the same time for the Massachusetts Division of Energy Resources.[1]

Average costs reflect the embedded cost of existing generation (including higher-cost nuclear and qualifying facilities contracts, and low-cost hydropower), while "marginal" costs reflect only the cost of the marginal generator expected to serve spot-market demands. Over time, these two values should and do converge. Nonetheless, because average costs do not fully reflect the "market value" of incremental generation, greater weight should be placed on forecasts of marginal costs (and prices). Forecasts of marginal costs (and prices) are typically derived from production cost simulation runs, but estimates of these costs beyond a limited timeframe are heavily dependent on input assumptions, especially assumptions on the cost of natural gas. Unfortunately, forecasted marginal cost data for New England (from the Massachusetts RPS analysis) were only available through 2012, and we were unable to quickly locate other publicly available sources for these data. (Greater searching may reveal such sources, and of course, forecasts of wholesale spot prices can be obtained at a cost from numerous private-sector vendors). We were also unable to quickly locate recent, reliable forecasts of wholesale market prices in other regions (we located one forecast for New York, but it was based on highly outdated gas price assumptions).

As a result, in the figure below, both marginal (from the MA RPS analysis) and average (from EIA) *one-year* cost data are compared to the *levelized* cost of energy (LCOE) of offshore wind energy per the NREL analysis. The distinction between *one-year* and *levelized* costs is notable: one-year costs represent the cost of generation in each individual year, while levelized costs represent the total life-cycle costs of new capacity built in each year (and operating for the next 20-30 years). Thus, the figure below likely presents a conservative estimate of the competitiveness of offshore wind; to the extent that fuel prices escalate in real terms over time, the levelized cost of generation will exceed the one-year cost of generation depicted in the figure. In other words, while the figure shows that offshore wind becomes competitive with average wholesale prices between 2015 (shallow) and 2020 (deep), on an LCOE basis, offshore wind will

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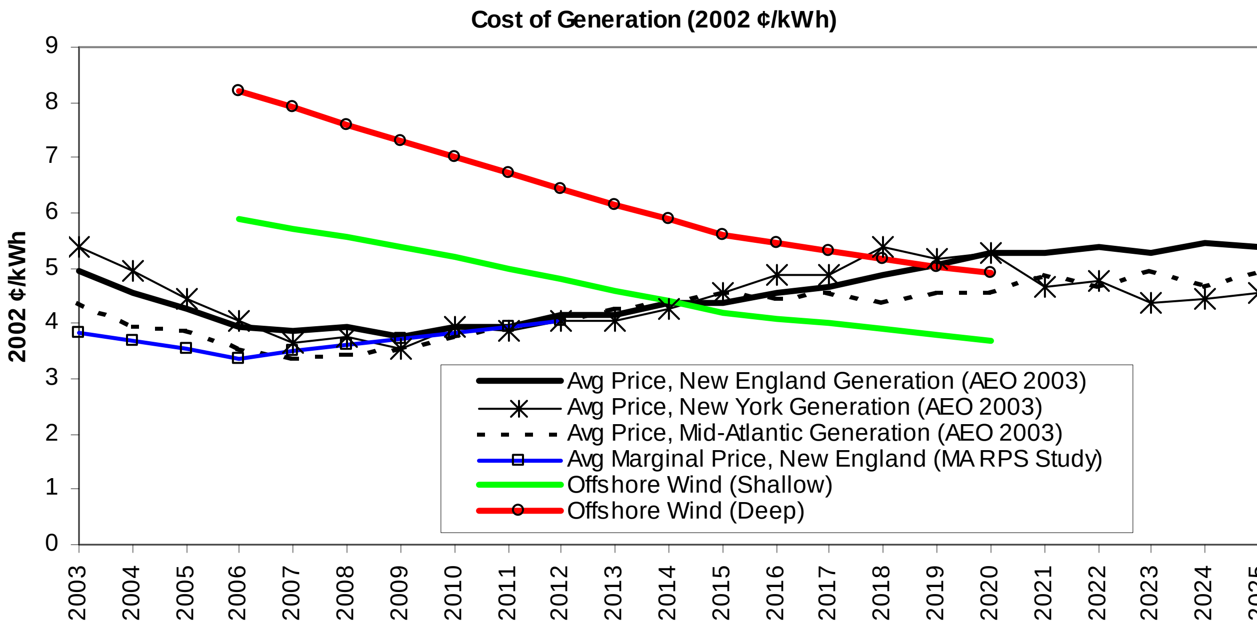
[1] *Massachusetts RPS: 2002 Cost Analysis Update – Sensitivity Analysis.* Presentation by R. Grace and K. Cory, presented to the MA RPS Advisory Group, December 16, 2002. http://www.state.ma.us/doer/programs/renew/rps-docs/CAU-SAP.pdf.

likely become competitive earlier than shown. Furthermore, marginal cost data appear to converge with average cost forecasts by 2012, so differences between marginal and average price streams may not be critical.



Because marginal cost data represents the most appropriate benchmark for the commodity value of wind power, and the data above present just one estimate of such prices for New England (and only through 2012), an alternative approach to estimating this value deserves consideration. Here we can rely on the fact that long-term forecasts of marginal wholesale spot prices should eventually converge to the cost of building new electric generating capacity (i.e., long-run marginal costs). Economic theory assures us that, in the long run, wholesale spot market prices cannot remain below the cost of building new generation capability.

The EIA does not provide a specific forecast of marginal wholesale electricity prices that we are aware of.[2] In AEO 2003, however, the EIA does estimate that the cost of electricity from a new advanced combined cycle unit in 2010 will be $49.4/MWh, and in 2025 will be $50.5/MWh (the cost increase is attributable exclusively to higher natural gas prices). Again, note that these appear to be "one-year" rather than "levelized" costs, as the EIA only forecasts natural gas prices through 2025. If one assumes that real gas prices will continue to escalate beyond 2025 at a rate equivalent to the average projected escalation rate of 1.4% from 2020-2025, then the *levelized* cost of energy (assuming a 25-year plant life) from a new combined cycle unit in 2010 increases to $52.4/MWh (a $3/MWh increase), while a new unit in 2025 will have a levelized cost of $54.2/MWh (a $3.7/MWh increase). Because most energy analysts assume that combined cycle units will be the primary technology constructed to serve incremental load in the Northeastern United States, these costs should be reflected in long-term wholesale spot market forecasts.

[2] As a benchmark of recent "marginal" prices, however, note that the NYISO 2002 annual average spot market price from day-ahead and real-time markets (including energy and ancillary services) was $49.77/MWh. The PJM prices in 2002 were $28.46/MWh day-ahead and $28.30/MWh real-time (average annual LMP), while ISO-NE prices were $41.75/MWh (including energy at $37.52, and ancillary services and capacity on top of this).

Shallow offshore wind is competitive with this long-run marginal cost by 2012, while deep offshore wind does not break 5.2¢/kWh until 2018.

Other Considerations

The competitiveness of wind power should not be evaluated solely with respect to wholesale price forecasts or the LCOE from new natural gas-fired generation. Other factors must be considered, such as wind integration costs, capacity value, production profiles and locational value, potential revenue from emissions credit markets, wind's hedge value against natural gas price risk, and potential revenue from the sale of renewable energy credits (RECs). Below we consider each of these in turn.

Wind Integration Costs

Because of its intermittency, wind may impost some costs on the grid, in terms of voltage regulation and load-following services, imbalance energy payments, and reserve requirements. Several recent studies of the costs of integrating large amounts of new wind capacity into specific utility grid systems, however, find that such costs are modest. For example, a study of Xcel Energy's service territory in Minnesota, sponsored by the Utility Wind Interest Group (UWIG), concluded that at current peak penetration levels of about 3.5% (280 MW of nameplate wind capacity on a 8,000 MW peak system), the cost of integrating wind is roughly 0.185¢/kWh. A similar study of We Energies' system in Wisconsin found wind integration costs ranging from 0.19-0.29¢/kWh for 250-2000 MW of wind capacity (which at the upper bound of 2000 MW, represents a penetration rate of 28% and 51% of projected peak and average load, respectively). In the Pacific Northwest, PacifiCorp estimates that it would cost about 0.5-0.6¢/kWh to integrate 1,000 MW of wind power (i.e., 20% of peak load) into its system, while another study estimates the cost to integrate 1,000 MW of wind power into the Bonneville Power Administration's hydro-based system to be "well under" 0.5¢/kWh. Studies conducted in other countries show similar results. While extrapolating these results to offshore wind development in the Northeast is somewhat risky, evidence is mounting that the cost of integrating wind into an electricity system (at even relatively aggressive levels of penetration) should be under 0.5¢/kWh.

Capacity Value

In addition to integration costs, it is also useful to consider the long-run "capacity value" of different resource options: the ability of generating capacity to add to the reliability needs of an electricity system. Wholesale markets in New England, New York, and the Mid-Atlantic do award some capacity credit to wind projects. Compared to a non-intermittent plant, however, wind's capacity value is likely to be smaller, roughly equal to (or, in the case of the Northeast, less than) its capacity factor multiplied by nameplate capacity. Even so, capacity credits provide an additional source of revenue, projected to reach $45/kW-year in New England in 2010 (this equates to roughly 0.15¢/kWh, assuming a 30% capacity credit).[3] Because wind generation does not provide 100% capacity value, however, comparisons of the cost of wind-generated electricity to the cost of a new combined cycle gas plant should be done with care: the commodity market value of wind is expected to be lower than that of a new combined cycle unit. We have not had time to assess this issue in detail for the purpose of this memo.

[3] *Massachusetts RPS: 2002 Cost Analysis Update – Sensitivity Analysis.* Presentation by R. Grace and K. Cory, presented to the MA RPS Advisory Group, December 16, 2002. http://www.state.ma.us/doer/programs/renew/rps-docs/CAU-SAP.pdf.

Production Profiles and Locational Value

Related somewhat to capacity value and integration costs is the fact that wind-generated electricity has diurnal and seasonal profiles that differ from both average system load and baseload generation options. Again, because of this feature, comparing the cost of wind to the marginal cost of wholesale power on a yearly average basis should be done with care: wind's diurnal and seasonal profile may be less or more "attractive" than this yearly average marginal price. Related, the wholesale cost of power can vary greatly from one region to the next. The value of offshore wind cited off of Long Island, for example, will be substantially greater than the value of an equivalent quantity of wind located in Western New York. We have not assessed either of these two issues in this memo.

Wind Emissions Value

Though wind power is not directly granted SO_2 emissions allowances, is only granted limited NO_X emissions allowances in a few states, and carbon has not yet come under a cap and trade program, the zero-emission attribute of wind power can nonetheless be valued by examining the expected trading price of emissions allowances. At a minimum, the use of wind energy has the potential to avoid the need to purchase costly allowances for SO_2 and NO_X, and can provide a form of insurance against carbon risk. The data presented below are from Wooley (2001), and we make no effort here to independently validate this data.[4]

	Emissions Allowance Value ($/ton)	Tons Avoided per MWh of Renewable Energy*	Emissions Reduction Value ($/MWh)
NO_X	$2,000/ton	0.00075	$1.5/MWh
SO_2	$200/ton	0.006	$1.2/MWh
CO_2	$5/ton	0.6	$3.0/MWh
		Total:	***$5.7/MWh***

**The NO_X estimates are based on the likely allocation of allowances under EPA's NO_X SIP call in the eastern U.S. The SO_2 allowance allocation is based on that used to assign emission allowances to fossil generation under Phase II of the Clean Air Act acid rain program. The CO_2 estimate is based on average emissions/MWh of fossil generation in the U.S., discounted by 25% to reflect the likely effect of a CO_2 cap on retirement of older coal-fired generation.*

Note that NO_X and SO_2 are currently trading around these values, but we do not have a long-term projection of NO_X and SO_2 allowance prices. $5/ton for CO_2 is likely a conservative estimate were a carbon market to develop, but at this point the carbon value should be viewed as speculative, at best.

Wind "Hedge Value"

The cost of natural gas generation is inherently uncertain. The EIA gas price forecast used in the AEO2003 model runs was generated in the fall of 2002, at a time of relatively low gas prices and prior to the most recent price surge (note that the Massachusetts RPS analysis was conducted at approximately the same time). As a result, the EIA gas price forecast (and the generation cost forecasts based on it and presented above) is now out of date and out of tune with the market's view of gas prices in the coming years.

[4] Wooley, D.R. and E.M. Morss. 2001. *The Clean Air Act Amendments of 1990: Opportunities for Promoting Renewable Energy*. NREL/SR-620-29448.

For example, NYMEX natural gas futures prices are listed out six years, and for the period 2004-2009, are now \$1.40/MMBtu higher on average than the EIA gas price forecast (delivered to electricity generators) used in AEO 2003. At a heat rate of 7,000 Btu/kWh, this \$1.40/MMBtu difference translates into a 1¢/kWh increase from advanced combined cycle units over this six-year period. The cost of wind power, on the other hand, is not impacted by changes in natural gas prices.

If future gas prices were expected to remain at these higher levels, relative to the AEO 2003 gas price forecast, then in 2010 the levelized cost of a new CCGT would be ~\$62.4/MWh, and in 2025 would be ~\$64.2/MWh. The projected cost of offshore wind would be very attractive relative to these levels. In either case, wind power provides an important hedge against volatile and uncertain gas prices.

Moreover, increased use of wind will also reduce aggregate natural gas demand, putting downward pressure on natural gas prices. This effect has been analyzed by the EIA and others in recent studies of a national RPS, and is the subject of ongoing research by Berkeley Lab.

Renewable Energy Credit Prices

There is demand for renewable energy credits (RECs) in the Northeast due both to demand under state RPS policies (MA, CT, NJ, NY in future, etc.), and due to voluntary consumer demand. REC prices for new wind generation are currently trading around \$40/MWh in New England, while in New Jersey Class I RECs (offshore wind falls in this category) currently command about \$6/MWh (the more stringent RPS requirements of New England, relative to the Mid-Atlantic, largely explain the cost difference).[5] December 2002 analysis of the costs of the Massachusetts RPS projected RECs trading above 2.5¢/kWh through 2012.[6] A recent 2003 analysis of the possible New York RPS also estimated REC prices trading at or above 2¢/kWh through 2013.[7] To the extent that existing state RPS policies continue, or are enhanced, wind-generated electricity will continue to command a premium over commodity electricity prices. With just voluntary customer demand, that premium is unlikely to exceed 1¢/kWh, and volume will be limited. With RPS driven demand, and as demonstrated above, the premium could exceed 2.5¢/kWh on a long-run basis. This would make offshore wind, at the costs forecast by NREL, especially attractive.

[5] www.evomarkets.com

[6] *Massachusetts RPS: 2002 Cost Analysis Update – Sensitivity Analysis.* Presentation by R. Grace and K. Cory, presented to the MA RPS Advisory Group, December 16, 2002. http://www.state.ma.us/doer/programs/renew/rps-docs/CAU-SAP.pdf.

[7] NY State Department of Public Service. 2003. "New York Renewable Portfolio Standard Cost Study Report." Prepared by NY DPS, NYSERDA, Sustainable Energy Advantage, and LaCapra Associates.